Ontario Reserve Margin Requirements

From 2019 to 2023

PUBLISHED DECEMBER 21, 2018

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Executive Summary

Through the annual release of the *Ontario Reserve Margin Requirements* (ORMR) report, the IESO communicates Ontario's planning reserve margins required over the next five years to reliably supply the province's forecast demand, as required in Section 8.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria*[1] (ORTAC).

Section 8.1 of the ORTAC refers to the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in NPCC Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*[2]. The reserve margin requirement in any year presented in this report is the amount of supply resources in excess of the annual peak demand needed to meet the NPCC reliability criterion of an annual loss of load expectation (LOLE)[3] of 0.1 days/year using the application approach required in Section 8.2 of the ORTAC. It is expressed as a percentage of annual peak demand.

The IESO uses the *General Electric Multi-Area Reliability Simulation* (MARS) program to derive annual reserve margin requirements. The MARS model includes the available capacity and operational characteristics of existing and planned resources; capacity and energy limitations of renewable resources; resource planned outages and equivalent forced outage rates on demand; retirement and refurbishment schedules; interface limits between Ontario's 10 electrical zones; demand forecast; and demand forecast uncertainty over the study horizon.

Ontario's reserve margin requirement to meet an annual LOLE of 0.1 days/year ranges from 17.4 percent to 21.7 percent over the five-year study period. In order to compare the reserve margin requirement to previous editions of the ORMR, this report also presents the reserve margin requirement excluding the impact of nuclear refurbishment performance risk. By excluding nuclear refurbishment performance risk, the reserve margin requirement reduces on average by 0.5 percentage points, and ranges from 17.2 percent to 19.9 percent. Table 1 below presents the annual reserve margin requirement results of the study.

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[1] IMO_REQ_0041 "Ontario Resource and Transmission Assessment Criteria" can be found at www.ieso.ca
[2] NPCC Directory # 1: Design and Operation of the Bulk Power System, can be found at www.npcc.org
[3] LOLE is a common reliability index used to assess resource adequacy. It represents the number of days per year, on average, in which the demand exceeds the available resource capacity, and hence, there is an expectation that firm load will be disconnected to resolve resource deficiencies.

Table 1 | Ontario Reserve Margin Requirements by Year

Year	2019	2020	2021	2022	2023
Reserve Margin (%), with refurbishment risk	17.4	21.7	18.8	19.7	19.6
Reserve Margin (%), without refurbishment risk[4]	17.2	19.0	19.1	19.9	19.3

The ORTAC's requirements for capacity planning are more stringent than those required by NPCC criteria. Specifically, the ORTAC states:

> For capacity planning purposes, where longer term decisions must be made, additional reserves to cover residual uncertainties and project delays may be appropriate. Also, the IESO does not consider emergency operating procedures for longer term capacity planning because the relief provided by these measures is intended for dealing with emergencies rather than being used as a surrogate resource. Regular triggering of emergency operating procedures rather than developing appropriate resources could lead to the erosion of these options through overuse.

Looking Ahead

The publication of the ORMR is one way that the IESO continues to update and refine its resource adequacy forecasts. The IESO plans to engage stakeholders in 2019 through its development of an updated *Planning Outlook*. Access to this information will enable market participants to work collaboratively with the IESO to help ensure Ontarians continue to have the energy they need to power their homes and businesses. Starting in 2019, the *Planning Outlook* will supersede this annual *Ontario Reserve Margin Requirements* report and will be the vehicle for the IESO to meet the requirements stated in Section 8.2 of the ORTAC.

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[4] The incremental planning reserve is less in a few years because in some scenarios, the delay of return to service in one unit causes the refurbishment start of subsequent units to be deferred, resulting in fewer units on outage overall than under scenarios with no delays. As a result, more units could potentially be available, reducing the overall reserve requirement in those years.

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1. Introduction

Through the annual release of the *Ontario Reserve Margin Requirements* (ORMR), the IESO reports the planning reserves ("reserve margins") required in Ontario over the next five years to reliably supply Ontario's forecast demand. This report fulfills the requirements of Section 8.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria*[5].

Reserve margin requirements are determined in accordance with the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*[6]. The criterion states:

> "Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year."

Directory #1 further states that in meeting this requirement, the Planning Coordinator or Resource Planner shall:

> "Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

The LOLE represents the number of days per year on which supply is expected to be insufficient to meet demand. The reserve margin requirement in any year is the amount of resources in excess of the annual peak demand needed to meet the resource adequacy criterion of an annual LOLE of 0.1 days/year.

Currently, Ontario's reserve margin requirements are determined without reliance on emergency operating procedures or support from neighbouring Planning Coordinator Areas through non-firm imports. However, experience shows that Ontario's interconnections can be relied on during times of need and that occasional use of the interties to support Ontario's reliability is feasible. In light of this, the IESO is continuing to investigate the potential for considering non-firm imports to reduce

[5] IMO_REQ_0041 "Ontario Resource and Transmission Assessment Criteria" can be found at www.ieso.ca
[6] NPCC Directory # 1: *Design and Operation of the Bulk Power System*, can be found at www.npcc.org

future reserve margin requirements where the level of assumed interconnection support must reflect prevailing conditions.

1.1 Interpretation

The IESO completes several assessments relating to resource adequacy each year. While efforts are made to ensure alignment and consistency between assessments, there are some inherent differences between the purposes and assumptions in various reports. This section provides a discussion on publicly available reports discussing Ontario's resource adequacy in the next five years.

The NPCC Comprehensive Review of Resource Adequacy, approved by the NPCC Reliability Coordinating Committee (RCC) on December 4, 2018 confirmed that the Ontario system is expected to satisfy the NPCC resource adequacy criterion over the five-year study period 2019 to 2023. The findings in the Comprehensive Review of Resource Adequacy assumed that all planned resources come into service on time and that there are no additional risks related to nuclear refurbishment.

The IESO's analysis that was submitted in the Comprehensive Review identified periods where emergency operating procedures may be triggered in the absence of outage coordination. The report concluded that the NPCC criterion is satisfied for 2019 and 2020 with existing and planned resources, based on the existing outage plan. For 2021 and 2022, the IESO can reschedule outages and rely on Emergency Operating Procedures (EOPs) to satisfy the NPCC criterion (while the NPCC criterion allows the use of EOPs, the ORTAC does not and therefore EOPs were not applied in this Ontario Reserve Margin Requirements Report). In 2023, the use of EOPs, outage rescheduling, a firm import from Quebec and up to 100 MW of support from neighbouring Planning Coordinator Areas in the form of tie benefits were used to satisfy the criterion.

In recognition of the importance of outage coordination in the coming years to ensure resource adequacy, the IESO's Extended 18 Month Outlook provides a five year view of the drivers – including nuclear refurbishments, changing transmission flow patterns, and end of contracts – that can affect resource adequacy, and identifies periods where associated reliability risks may be managed through scheduling of outages. The provision of detailed, transparent information to the market is an integral part of outage coordination between the IESO and market participants.

The IESO's Technical Planning Conference, held in September 2018, identified a potential capacity requirement for 2023. The findings of both the Comprehensive Review of Resource Adequacy and the ORMR confirm the capacity requirement while also assuring that the IESO has the mechanisms to ensure continued compliance with regulatory requirements. The assumptions used for the analysis presented at the Technical Planning Conference are different from those presented in both the Comprehensive Review of Resource Adequacy and this ORMR. The information presented that the Technical Planning Conference presents seasonal requirements, while this report presents annual requirements. Another significant difference is that this report is assesses the ability to serve demand on the IESO-controlled grid, while the assessment presented at the Technical Planning Conference is based on total Ontario demand net of conservation. The differences in assumptions, as well as the use of updated information in the ORMR, cause slight variations in the magnitude of the potential gap in 2023.

2. Reserve Margin Study Methodology

In deriving the annual reserve margin requirements, the IESO uses General Electric's Multi-Area Reliability Simulation (MARS) program, a probabilistic simulation tool that is widely used in the industry.

The IESO's MARS model includes detailed demand and resource information and a simplified 10-zone transmission network with inter-zonal transfer limits included. For more information on the IESO's MARS simulation approach, see Appendix A.

2.1 Study Inputs[7]

To accurately reflect the available capacity of existing and planned resources and forecast demand over the study horizon, the following details are modelled:

- Monthly maximum continuous ratings (MCR) of thermal units (nuclear, gas, oil and biofuel) based on information provided by market participants (MPs);
- Planned outage schedules of thermal units as supplied by MPs or estimated by the IESO;
- Nuclear refurbishment schedules from nuclear operators;
- Equivalent Forced Outage Rates on demand ($EFOR_d$) of thermal units, calculated by the IESO based on actual (historical) forced outage data and energy production data;
- Energy and capacity limitations of renewable resources (hydro and biofuel) provided by MPs or calculated by the IESO;
- Effective capacity available from Demand-Side Management: Demand Response (DR) and Dispatchable Loads;
- Variability in the production capability of wind resources;
- Expected hourly production capability of solar resources including monthly and seasonal variations;
- Ontario's 10 major electrical zones with defined inter-zonal transmission limits;
- Hourly coincident demand forecasts for Ontario's 10 electrical zones; and
- Load forecast uncertainty driven primarily by weather variability that affects demand.

[7] The study inputs were finalized based on the information available to the IESO as of July 31st, 2018.

The target in-service dates of planned resources are also reflected in the study. Planned retirements and long-term refurbishment outages of existing resources over the planning horizon are also scheduled according to their expected out-of-service and return-to-service dates. Risks related to nuclear refurbishment performance are also reflected in the study.

Also modelled in MARS is the Ontario-Quebec Electricity Trade Agreement under which Ontario will make 500 MW of capacity available to Quebec from December to March until 2023. The study reflected the option for Ontario to utilize 500 MW of capacity from Quebec as part of the agreement in summer 2023.

A more detailed description of the study methodology and key model assumptions is provided in Appendix A.

2.2 Base Case and Criteria Assessment Methodology

2.2.1 Regulatory Compliance Assessment

In conducting the analysis for each study year, an initial simulation is performed with the system "as-is" and the LOLE results are noted. The adequacy of this initial case is evaluated by comparing the LOLE for each year to the NPCC criterion of 0.1 days/year. Adjustments to the timing of planned outages are made as described in Section A.4 of the Appendix to produce a Modified Compliance Case. The aim of these changes is to reduce the annual system risk below the threshold of 0.1 days/year, thereby demonstrating compliance with the NPCC Directory #1 requirement.

2.2.2 Planning Requirement Assessment (Base Case)

In order to evaluate an appropriate planning reserve requirement, the ORTAC states:

> "For capacity planning purposes, where longer term decisions must be made, additional reserves to cover residual uncertainties and project delays may be appropriate."

As the primary purpose of the ORMR is for capacity planning, the 2017 ORMR incorporated an additional risk with respect to nuclear performance. This risk, referred herein as nuclear refurbishment performance risk, is an estimation of uncertainties surrounding the nuclear refurbishment program, such nuclear refurbishment return-to-service delays and nuclear unit performance degradation just before and after refurbishment. Considering this additional risk in the assessment usually causes the reserve margin requirement to be higher.

2.2.3 Criteria Assessment

The goal of the Criteria Assessment is to determine the minimum amount of Ontario resources needed to satisfy the LOLE criterion of 0.1 days/year. Starting with the Planning Requirement case for each year, this assessment is performed by iteratively running the simulation while reducing the available resources until an LOLE of 0.1 days/year is achieved.

During the Criteria Assessment, several factors are considered when deciding on which candidate resources should be removed in any year. These include:

Equivalent forced outage rate on demand ($EFOR_d$) – units with higher $EFOR_d$ are prime candidates for removal since their effective load-carrying capability (ELCC), i.e., the increase in system load that can be served at a particular reliability level after including the unit, is lower than units with a lower $EFOR_d$. Thus, removing a unit with a comparatively lower ELCC (high $EFOR_d$) will have a lesser impact on system LOLE than a unit of higher ELCC (lower $EFOR_d$), thereby allowing for removal of even more capacity until the LOLE criterion is achieved.

- Location – resources located in an export-constrained zone are also suitable candidates for removal since congestion on the transmission interface means units at that location do not benefit the system to the same extent as units located elsewhere.
- Unit size – during the unit removal process, units of smaller size and comparatively lower $EFOR_d$ may have to be removed in preference to larger units of higher $EFOR_d$, simply because removing the larger unit will cause the system LOLE to exceed the 0.1 days/year target.

If resources are required to reach the 0.1 days/year target, proxy natural gas-fired simple cycle gas turbines are added to the Toronto zone, which is not export-constrained. The proxy generator(s) has (have) a maximum installed capacity of 300 MW and an $EFOR_d$ of 2.4%. By following the above guidelines, the Criteria Assessment will yield a near minimal resource requirement. The Reserve Margin Requirement for each year is then calculated as the difference between the available resources and the annual peak demand. Reserve Margin Requirements are presented in Section 4.

3. Reserve Margin Study Results

3.1 Planning Requirement (Base Case Results)

Based on the methodology described previously, several resource mix scenarios could be used to meet the LOLE target of 0.1 days/year. By applying the guidelines outlined in Section 3.2, a near minimal reserve margin requirement in each year is achieved. The results are presented in Table 3-1. For each year of the study period, they include the resultant LOLE, required available resources, projected system peak demand and required reserve margins expressed in both megawatts (MW) and percent of peak demand. In each year, the system peak demand is forecast to occur in July.

Over the five-year study period, the required reserve margins vary between 17.4 percent and 19.6 percent. Year-to-year variations are influenced primarily by changes in annual demand forecasts and generator planned outage (including refurbishment) schedules. For example, a demand profile with a higher load factor[8] or an increase in the average generation capacity on planned outage will tend to increase reserve requirements.

The implied capacity requirement is approximately 1,350 MW emerging in 2023, without the use of emergency operating procedures.

Table 3-1 | Summary of Planning Requirement (Reserve Margin with Refurbishment Risks)

	2019	2020	2021	2022	2023
LOLE (days/year)	0.1	0.1	0.1	0.1	0.1
Required Capacity at Peak (MW)	25,840	26,868	26,315	26,447	26,467
Annual Peak Demand (MW)	22,016	22,085	22,155	22,098	22,139
Reserve Margin Requirements (MW)	3,824	4,783	4,160	4,349	4,328
Reserve Margin Requirements (%)	17.4	21.7	18.8	19.7	19.6

The reserve margin requirement represents the minimum resources in excess of the peak demand that are needed to satisfy the NPCC resource adequacy criterion in each of the next five years. These values take into account forecast demands (including peak demand and load shape) and

[8] Load factor is defined as the ratio of the 'average' load to the 'maximum' load. A higher load factor indicates that the demand is relatively constant, while a low load factor indicates that the high demand is only set occasionally.

load forecast uncertainty; scheduled and unscheduled generation outages; nuclear refurbishment schedules; seasonal capacity derates; energy and capacity limitations of renewable resources; and major transmission interface limits. The IESO's base case considered the impacts of nuclear refurbishment performance risks (impact of nuclear refurbishment return-to-service delays and nuclear unit performance degradation just before and after refurbishment). The IESO expects to have a better understanding of the nuclear refurbishment performance by 2020 and will continue to refresh outlooks and associated impact on reserve margin requirements as new information becomes available.

The required capacity is an amount of supply resources equal to the sum of the annual peak demand and the reserve margin requirement.

3.2 Modified Compliance Case Results

For completeness, the available reserve margins for the next five years determined from analysis of the Modified Compliance Case are presented in Table 2-1. Table 2-1 shows that Ontario satisfies the NPCC criterion over the planning period, without the use of non-firm imports until 2023. In 2023, the anticipated LOLE without non-firm imports exceeds the resource adequacy criterion of 0.1 days LOLE/year. The implied capacity requirement is approximately 1,300 MW, without the use of emergency operating procedures[9]. This amount is well within the amount of non-firm imports (tie benefit support) the IESO can expect from its neighbours.[10]

Table 3-2 | Modified Compliance Case LOLE Results and Reserve Margins

	2019	2020	2021	2022	2023
LOLE (days/year)	0.001	0.050	0.058	0.057	0.337
Available Capacity at Peak (MW)	28,648	26,913	26,892	26,988	25,615
Annual Peak Demand (MW)	22,016	22,085	22,155	22,098	22,139
Reserve Margin (MW)	6,632	4,827	4,737	4,890	3,476
Available Reserve Margin (Modified Compliance Case) (%)	30.1	21.9	21.4	22.1	15.7

[9] While the NPCC criterion allows the use of emergency operating procedures to meet requirements stated in Directory #1, the ORTAC does not. As a result, the required tie benefit support described in the Comprehensive Review of Resource Adequacy to meet the criterion differs from this report.
[10] The 2015 NPCC CP-8 study entitled "Review of Interconnection Assistance Reliability Benefits," published in December 2015 assessed that approximately 4,414 MW of interconnection assistance is reasonably available to the Ontario system by 2020. The most recent report is available at: https://www.npcc.org/Library/Interconnections%20Assistance%20Reliability%20Benefits/RCC_Approved_CP-8_Tie_Benefit_Report_2016-03-02.pdf

To allow readers to compare this year's ORMR to those requirements published in December 2017, the IESO determined the reserve requirement using the Modified Compliance Case. This allows a comparison to understand how the results described in Section 3.1 would vary if nuclear refurbishment performance risks were excluded in the analysis.

The results are presented in Table 3-3. For each year of the study period, they include the resultant LOLE, required available resources, projected system peak demand and required reserve margins expressed in both megawatts and percent of peak demand. It found, on average, the exclusion of these risks reduced the reserve margin requirement by 0.5 percentage points, to 18.9 percent. The implied capacity requirement under this sensitivity analysis is approximately 1,300 MW emerging in 2023, without the use of emergency operating procedures.

Table 3-3 | Summary of Reserve Margin Requirements, without Refurbishment Risks[11]

	2019	2020	2021	2022	2023
LOLE (days/year)	0.1	0.1	0.1	0.1	0.1
Required Capacity at Peak (MW)	25,808	26,279	26,392	26,503	26,407
Annual Peak Demand (MW)	22,016	22,085	22,155	22,098	22,139
Reserve Margin Requirements (MW)	3,792	4,194	4,237	4,405	4,268
Reserve Margin Requirements (%)	17.2	19.0	19.1	19.9	19.3

[11] These results are based on the assumption that all planned resources for the next five years will be delivered on time.

4. Conclusions

Ontario’s Reserve Margin Requirement to meet an annual LOLE of 0.1 days/year ranges from 17.4 percent to 21.9 percent over the five-year study period when considering risks related to nuclear refurbishment performance. Without nuclear refurbishment performance risks, the Ontario Reserve Margin Requirement ranges from 17.2 percent to 19.9 percent over the five-year study period.

The Ontario system satisfies the resource adequacy criterion in Section 8.2 of the ORTAC over the five year study period 2019 to 2023. Through prudent planning and a commitment to cost-efficiency, the IESO will competitively acquire resources when needed to ensure Ontario consumers have a reliable supply of electricity at lowest cost.

A. Modelling Assumptions

A.1 MARS Program

For the purposes of this study, the IESO used the Multi-Area Reliability Simulation (MARS) program. The MARS program is capable of performing the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools. A sequential Monte Carlo simulation forms the basis for MARS. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures would be implemented in each zone and pool.

A.2 Load Model

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its 10 zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. The forecast also accounts for conservation, price impacts and embedded generation.

Weather is represented by a Monthly Normal weather scenario which uses the last 31 years of historical weather data to generate typical or average monthly weather. This approach results in a monthly peak demand with a 50/50 probability of being exceeded. This methodology is in lieu of using a base year to scale the forecast demand shape. A measure of uncertainty in demand due to weather variability is used in conjunction with the Normal weather scenario to generate a distribution of possible demand outcomes. In the MARS program, demand is modelled as an hourly profile for each day of each year of the study period. An allowance for load forecast uncertainty (LFU) is also modelled.

The economic drivers are generated using a consensus of publicly available provincial forecasts, along with economic forecasts from service providers. Demographic projections are publicly available from the Ontario's Ministry of Finance.

Conservation impacts are incorporated into both the demand history and forecast where the final demand forecast is reduced to account for those conservation savings. The conservation assumptions, incremental to 2018, as per the 2017 Long Term Energy Plan, are provided in Table A-1.

Table A-1 | Conservation Assumptions

	2019	2020	2021	2022	2023
Conservation (MW)	288	482	511	523	556

The demand forecast accounts for the impacts of embedded generation. Capacity projections based on projected generation are combined with historical production functions to generate estimated hourly output. This information is then applied to the demand forecast to determine the need for grid-supplied electricity.

The annual energy consumption and peak demand for each year of the planning horizon are provided in Table A-2.

Table A-2 | Annual Energy Consumption and Peak Demand

	2019	2020	2021	2022	2023
Forecast Energy (TWh)	134.0	133.7	133.3	133.2	133.2
Forecast Peak (MW)	22,016	22,085	22,155	22,098	22,139

Load Forecast Uncertainty

The Load Forecast Uncertainty (LFU) curve is a probabilistic model representing probability of occurrence of various peak demands. The uncertainty in peak demand is mainly due to random weather fluctuations, and does not include any long-term economic influence. The temperature combined with the other load-contributing weather factors is denoted as Temperature Variable (TV). THI – temperature-humidity index, one of the variants of TV, is used for the study. Historical weather is used to simulate a set of peak loads with all other variables being equal. A Poisson distribution is used to deduce the expected peak loads for each probability bin from the expected rates of occurrence of peak loads belonging to each bin.

A zonal LFU curve is developed for every month of the year and applied to each transmission zone.

A.3 Demand-Side Management Representation

There are two main Demand-Side Management mechanisms at the IESO that are modelled as resources: Demand Response (DR) and Dispatchable Loads. Demand Response capacity is procured through an annual DR auction. Resources with capacity obligation are required to be available for curtailment up to their secured capacity during times of system need. The former Capacity Based Demand Response (CBDR) program ended as of October 2018. Procured capacity under this program has successfully transitioned to the DR auction. Resources which are contracted solely to provide ancillary services are not included in capacity adequacy assessments. Dispatchable Loads are loads that bid into the market and are dispatched economically like other resources without participating in the Demand Response Auction. Table A-3 describes the assumed Demand-Side Management in the ORMR.

Table A-3 | Demand-Side Management Assumptions

	2019	2020	2021	2022	2023
Gross Demand Management – Summer (MW)	857	857	857	857	857
Effective Demand Management – Summer (MW)	533	533	533	533	533
Gross Demand Management – Winter (MW)	998	998	998	998	998
Effective Demand Management – Winter (MW)	793	793	793	793	793

The IESO treats DR as a resource. As such, to maintain consistency, the impacts of DR programs are added back to the historical data when forecasting demand. Effective values of DR programs are used in MARS to reflect dependable capacity.

Effective capacity available from Dispatchable Loads is determined based on historical capacity offered, using five-year history, by the participants during peak demand hours. In MARS, Dispatchable Loads are modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.

Effective capacity for DR is determined based on historical performance of the participants of individual programs. In MARS, DR is modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.

Price impacts from time-of-use rates and critical peak pricing programs are treated as load modifiers and decremented from the demand forecast. In Ontario, some participants of Demand-Side Management programs also participate in a critical peak pricing program.

A.4 Supply-Side Resource Representation

This study considers all existing resources as well as planned resources expected to come into service over the period from 2019 to 2023. Planned retirements expected to occur over this timeframe are also considered, as are the refurbishment schedules of Ontario's nuclear fleet. The

IESO estimate of future retirements is based on information provided annually by Market Participants to the IESO. In this assessment, the only estimated retirements are those facilities whose contracts expire and the facility itself has reported to the IESO that they do not plan to continue operation after the expiry of the contract. This study includes the expectation that up to 1,405 MW of capacity will reach end of life or current contractual obligations by the end of 2023, of which 1,030 MW arise from the retirement of two nuclear units at the Pickering Nuclear Generating Station at the end of 2022.

Thermal Resources

Four resource types are modelled as thermal resources: nuclear, gas, oil and biofuel. The capacity values for each unit are modelled on a monthly granularity, to capture external factors such as ambient temperature and humidity or cooling water temperature. For nuclear generators and the like whose MCR is not ambient temperature sensitive, the IESO models the generator's expected monthly gross MCR and their station service load (as submitted annually by the generator). Fossil- or biofuel-fired generators whose MCR is sensitive to ambient temperature provide gross MCR at five different temperatures specified by the IESO which are used to construct a temperature derating curve. For each such generator, monthly gross MCR values calculated at normal monthly temperatures using the derating curve.

Planned and maintenance outages are explicitly modelled, generally using outage submissions from market participants as of July 24, 2018. During the Basecase Assessment and to the extent possible, planned outages are modelled as submitted, within the limitations of the MARS software. However, in instances where the planned outage schedule includes multiple overlapping outages that significantly increase system LOLE, adjustments to the timing of the relevant outages are made based on technical judgement. These adjustments are intended to reflect the improved coordination that would ordinarily be achieved through the IESO's outage management process which seeks to ensure that equipment outages do not unduly impact the reliability of the IESO-controlled grid.

During the Criteria Assessment, as resources are added or removed to bring the system LOLE to 0.1 days/year, the planned outage schedule is further modified as necessary to minimize the system LOLE and thereby facilitate further resource removals. These additional outage schedule adjustments are made in keeping with the previously stated approach and avoid the artificial inflation of reserve requirements by an outage schedule that in reality, would be better coordinated closer to real-time through the outage management process. Notwithstanding the adjustments to timing, the full outage duration needs of each facility are still accommodated.

For those generating units with no specified outages over the planning period, planned outages are based on forecast planned outage factors (POFs) submitted by market participants and/or a generic outage plan derived from historic outage patterns of existing units. Planned and forced outage impacts for non-thermal resources are assumed to be already accommodated in the energy/capacity assumptions used.

Starting in late 2016, the IESO transitioned to using Equivalent Forced Outage Rate on demand ($EFOR_d$). $EFOR_d$ is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate[12]. It is the most appropriate metric for modelling the forced outage rates given the capabilities of the assessment tools used by the industry. $EFOR_d$ of existing units are derived based on an analysis of a rolling five-year history of actual forced outage data and the generator's energy production data. The derived $EFOR_d$'s are then converted to capacity state and transition rate matrices for MARS. For existing units with insufficient historical data, and for new units, $EFOR_d$ values of existing units of similar size and technical characteristics are used.

The projected $EFOR_d$ values in the form of weighted average and range by fuel type are provided in Table A-4.

Table A-4 | Ontario Projected Equivalent Demand Forced Outage Rates

Fuel Type	Weighted Average $EFOR_d$	Range of $EFOR_d$
Nuclear	6.7%	2.2 – 10.9 %
Gas/Oil	10.6%	1.6 – 26.7%
Biomass	8.4%	2.3 - 10.8%

Hydroelectric Resources

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each transmission zone. Monthly maximum capacity values are based on historical median energy production and contribution to operating reserve at the time of system weekday peaks. Minimum capacity values are based on the 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

[12] IEEE Std 762 - IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity

For new hydroelectric projects, the maximum capacity value, the minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of other generators in the zone where the new project is located.

Wind Resources

Wind resources are modelled probabilistically on a zonal basis as Type 1 Energy-Limited Resources with a cumulative probability density function (CPDF). In order to derive the CPDFs, first, the top five demand hour window by month for each shoulder period month and by season for summer and winter periods are determined based on five-year historical demand data. Historical wind production during these top five demand hours is then extracted to generate CPDFs. Seasonal CPDFs for the summer and winter, and separate monthly CPDFs for the shoulder months are modelled in MARS to represent the variable energy production of wind resources.

Solar Resources

Solar resources are modelled as load modifiers in MARS with production (MW contribution) calculated from projected installed capacities and hourly solar contribution factors. Hourly solar contribution factors are determined using 10 years of historical simulated data by calculating the hourly average solar contribution by month for each shoulder period month and by season for summer and winter periods. This methodology results in a 24-hour capacity factor that is used to create an hourly solar profile to modify load.

Firm Transactions

As part of the Amended and Restated Capacity Sharing Agreement between Ontario and Quebec, signed November 2016, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. As a result of the previous agreement, Quebec will provide Ontario a total of 500 MW of capacity in the summer months (June to September) to be exercised, when needed, any time before September 30, 2030. This capacity may be used once or be split into multiple summer periods, but cannot exceed 500 MW in total (e.g. 100 MW may be used in one year and 400 MW in another year). The entirety of this summer capacity was relied upon in this report.

To model the firm contract of 500MW with Quebec, a simplified representation of Quebec is created in MARS with a transmission line interface to Ottawa. This transmission line interface is limited to a maximum transfer capability of 500 MW. To model conservatively, over the winter months (December to March) a 500 MW load in Quebec is used to represent Ontario’s firm capacity export contract. The import is modelled in MARS as a 500 MW EOP in the Ottawa zone from June to September 2023.

Additional Nuclear Risks

The scope and complexity of the ongoing nuclear refurbishment program introduce new risks to resource adequacy. The additional nuclear refurbishment performance risk included in this report has two components: return-to-service delays and performance degradation. Return-to-service delay risk reflects the potential for nuclear units being delayed in their return to service following refurbishment. Performance degradation risk reflects the potential for nuclear units to have poorer performance, through increase forced outage rates, in the years preceding and following their refurbishment outage.

Return-to-service delay risk is determined by estimating probabilities for various return-to-service delay scenarios. These scenarios are compared against the planned refurbishment schedule to evaluate the potential effects on available nuclear capacity. In some scenarios, a delay may affect the timing of subsequent refurbishments. To reflect the chance of performance degradation, each scenario includes a chance of higher nuclear forced outage rates in the three years before and after a refurbishment.

The IESO will continue to work with the nuclear operators to improve assumptions and refine assessments of nuclear refurbishment performance risk.

A.5 Transmission System

The Ontario transmission system is represented by 10 interconnected zones with transmission limits between the zones explicitly modelled. Figure A.1 provides a pictorial representation of Ontario's 10 zones. The limits used in this study are the operating security limits (OSL) specified for each interface with appropriate representation of and limit increases due to planned transmission system enhancements.

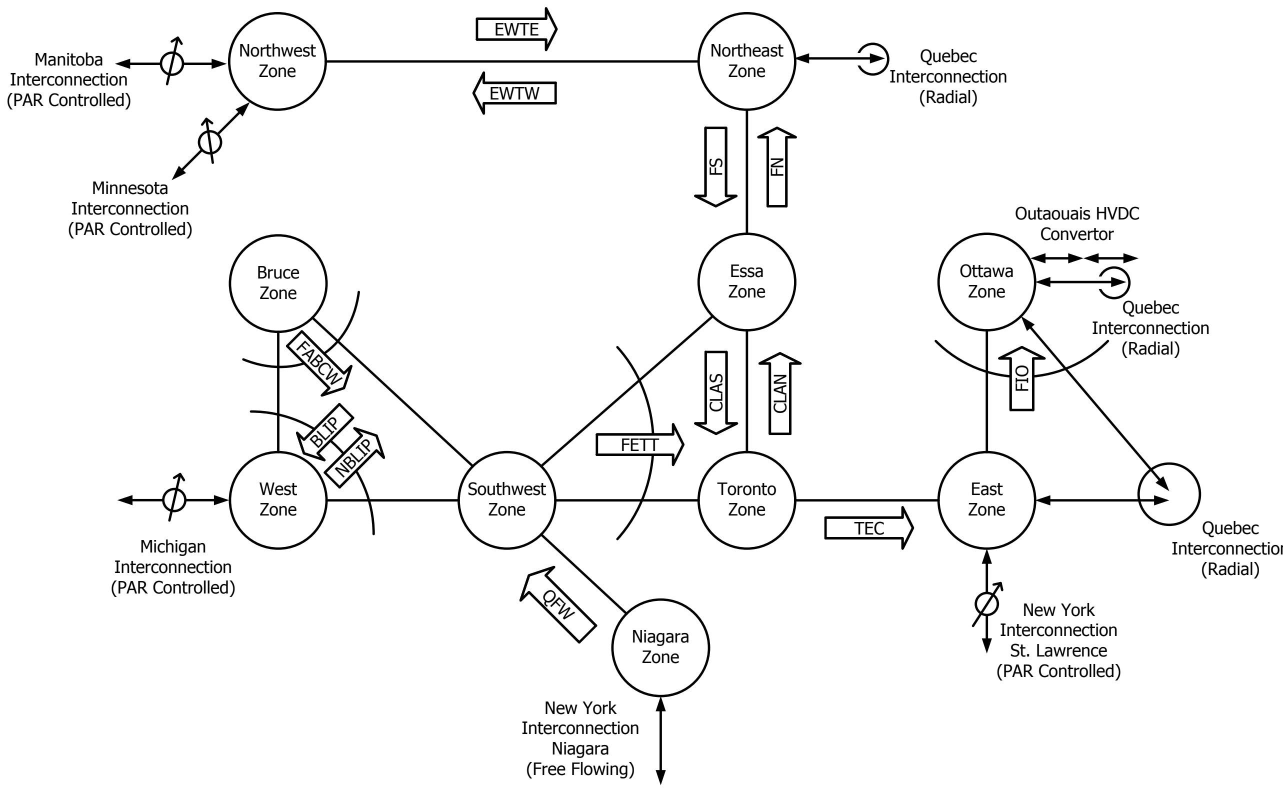

Figure 1 | Ontario's Zones, Interfaces, and Interconnections

B. Resources Referenced in This Report

The table below lists additional resources that were referenced in this report.

Table B-1 | Additional Resources

Number	Document Name	Document ID
1	Ontario Resource and Transmission Assessment Criteria	IMO_REQ_0041
2	Design and Operation of the Bulk Power System	NPCC Regional Reliability Reference Directory # 1
3	Review of Interconnection Assistance Reliability Benefits	None
4	IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity	IEEE Std 762™-2006

C. List of Acronyms

CBDR	Capacity Based Demand Response
DR	Demand Response
$EFOR_d$	Equivalent Forced Outage Rates on demand
EOP	Emergency Operating Action
IESO	Independent Electricity System Operator
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
MARS	General Electric Multi Area Reliability Simulation
MCR	Maximum Continuous Rating
MP	Market Participant
MW	Megawatts
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORMR	Ontario Reserve Margin Requirements
ORTAC	Ontario Resource and Transmission Criteria
OSL	Operating Security Limit
RCC	Reliability Coordinating Committee
TV	Temperature Variable
TWh	Terawatt-hours
WCC	Wind Capacity Contribution

Independent Electricity System Operator

1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca
@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/ieso

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